ANNUAL REPORT
of the
ALBERTA PETROLEUM MARKETING COMMISSION

pursuant to the
PETROLEUM MARKETING ACT
and
NATURAL GAS PRICING AGREEMENT ACT

for the fiscal year ended
December 31, 1982

TABLE OF CONTENTS

PAGE

PETROLEUM

Functions and Responsibilities 5
Petroleum, Pentanes Plus and Bitumen Sales 5
Petroleum, Pentanes Plus and Bitumen Pricing 7

NATURAL GAS

Functions and Responsibilities 8
Natural Gas Sales 8
Natural Gas Pricing 9
Alberta Cost of Service 11
Fund Transactions 12

OTHER ACTIVITIES

Regulatory Analysis 13
Special Studies 14
Syncrude Project 14

WORLD ENERGY SCENE

International 15
United States 17
Canada 19

FINANCIAL STATEMENTS

Petroleum 21
Natural Gas 28

COMMISSION PERSONNEL 32

Alberta

PETROLEUM MARKETING COMMISSION

403/262-8808

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August 31, 1983

The Honourable E.P. Lougheed, Premier
and
The Honourable John Zaozirny, Minister
Government of the Province of Alberta
Legislative Building
Edmonton, Alberta
T5K 2B7

Gentlemen,

In accordance with the provisions of the Petroleum Marketing Act and the Natural Gas Pricing Agreement Act, the Commission has prepared a general report summarizing its transactions and affairs during the fiscal year ended December 31, 1982. I have the pleasure to submit the 1982 Annual Report that you may lay a copy before the Legislative Assembly.

Respectfully,

D.W. Minion
Chairman

PETROLEUM

FUNCTIONS AND RESPONSIBILITIES

The Petroleum Marketing Act created the Commission as agent to sell the Crown's royalty share and lessee's share of petroleum and pentanes plus from Crown leases. Marketing of petroleum commenced March 1, 1974. Marketing of pentanes plus commenced on January 1, 1982.

The Commission administers the Act using procedures that embody the following:

- issuance of price bulletins in which the Commission prescribes selling prices for petroleum and pentanes plus;
- designation of operators to make deliveries of petroleum and pentanes plus from Crown leases to the Commission;
- movement of petroleum and pentanes plus from point of receipt to point of sale to buyers;
- sale of petroleum and pentanes plus by the Commission to buyers;
- remittance of proceeds of sale of the lessee's share to designated operators for distribution to owners;
- remittance of the proceeds of the Crown's royalty share to the Provincial Treasurer.

The Memorandum of Agreement between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation of September 1, 1981 (the 'Canada-Alberta agreement') established higher prices (NORP) for 'new' oil, effective January 1, 1982 and 'new' pentanes plus and bitumen effective April 1, 1982. Oil and pentanes plus eligible for 'new' status is that discovered after December 31, 1980. The National Energy Program Update of May, 1982 established, as of July 1, 1982, a special old oil price (SOOP) for producers for oil discovered between April 1, 1974 and December 31, 1980. Pentanes plus discovered between January 1, 1974 and December 31, 1980 also became eligible for SOOP.

The Commission sells all petroleum and pentanes plus at conventional old oil prices to buyers and administers the distribution of NORP and SOOP payments to producers out of funds received from the federal government for the difference between the conventional old oil prices and the NORP/SOOP prices.

In addition to marketing Crown lease petroleum, pentanes plus and bitumen, the Commission also purchases and markets these substances produced from lands other than Alberta Crown lands, upon specific agreements with owners.

PETROLEUM, PENTANES PLUS AND BITUMEN SALES

During the year the Commission sold 49.5 million cubic metres of petroleum, pentanes plus and bitumen from Crown and freehold lands. These sales, together with NORP and SOOP supplements totalling $352 million, realized total revenues of $8.16 billion. Of that amount, 45.9 million cubic metres worth $7.48 billion were from Crown lands. The Crown royalty share totalled 16.3 million cubic metres worth $2.59 billion.

During six months of the year light and medium crude oil was produced at capacity. In the remaining months shut-in production varied from a low of 5 100 cubic metres per day to a high of 51 800 cubic metres per day.

From January to May heavy crude oil production was shut in, in varying amounts, from a low of 3 200 cubic metres per day to a high of 6 000 cubic metres per day.

Monthly volumes of sales from Crown leases are shown in Figure 1, with the value of those sales shown in Figure 2.

FIG. 1
SALES VOLUMES FROM CROWN LEASES

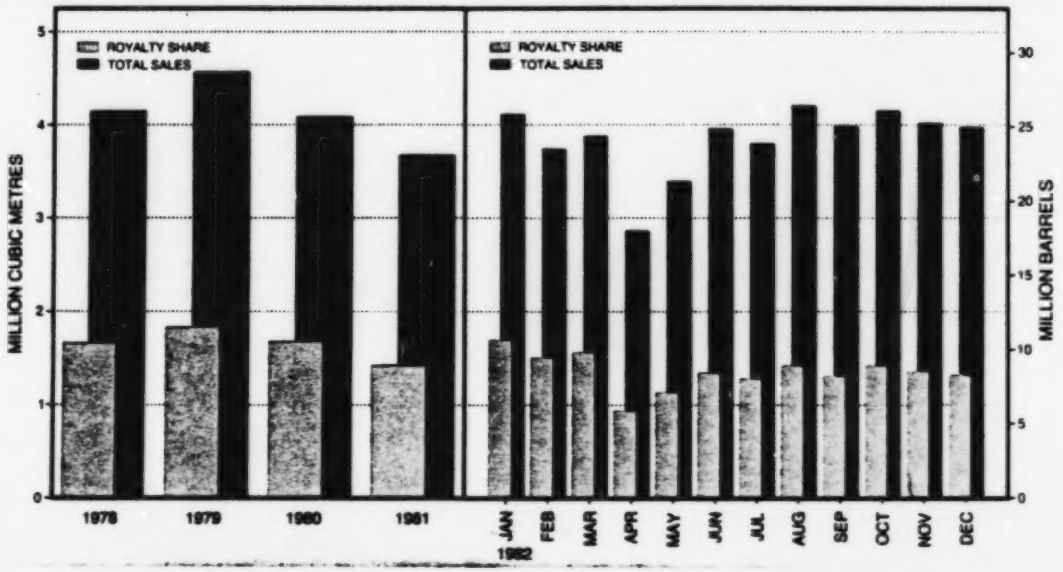
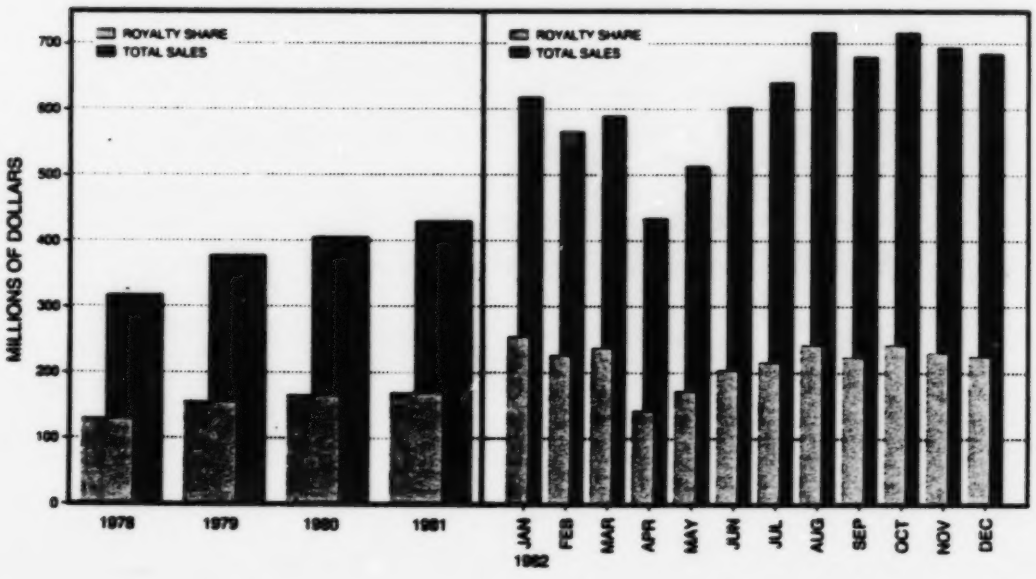


FIG. 2
SALES VALUES FROM CROWN LEASES



PETROLEUM, PENTANES PLUS AND BITUMEN PRICING

The Commission's price bulletins prescribe the prices for petroleum, pentanes plus and bitumen produced from Crown leases, incorporating variations in quality based on density and sulphur content with the object of maintaining an average field price as specified in the Canada-Alberta agreement.

The field prices during the year for petroleum with a density of 825 to 844 kilograms per cubic metre and a sulphur content of 2.5 to 4.9 grams per kilogram are shown in Table 1.

TABLE 1

Field Price

($ per cubic metre)

1982	Old Oil	NORP Oil	SOOP Oil
January-June	148.35	283.05	
July-September	162.50	265.70	190.95
October-December	162.50	277.90	197.90

Table 2 shows the average old oil field prices for conventional crude oil for the period from January 1, 1977 to January 1, 1983.

TABLE 2

Average Old Oil Field Price

Effective Date	Price Per Barrel	Price Per Cubic Metre
Jan. 1, 1977	$ 9.75	
July 1, 1977	10.75	
Jan. 1, 1978	11.75	
July 1, 1978	12.75	
July 1, 1979	13.75	$ 86.53
Jan. 1, 1980	14.75	92.83
Aug. 1, 1980	16.75	105.40
Jan. 1, 1981	17.75	111.70
July 1, 1981	18.75	117.99
Oct. 1, 1981	21.25	133.72
Jan. 1, 1982	23.50	147.88
July 1, 1982	25.75	162.04
Jan. 1, 1983	29.75	187.21

FUNCTIONS AND RESPONSIBILITIES

The Canada-Alberta agreement on natural gas pricing is implemented by the Natural Gas Pricing Agreement Act governing field prices of natural gas production in Alberta.

The functions and responsibilities of the Commission with respect to the Act are as follows:

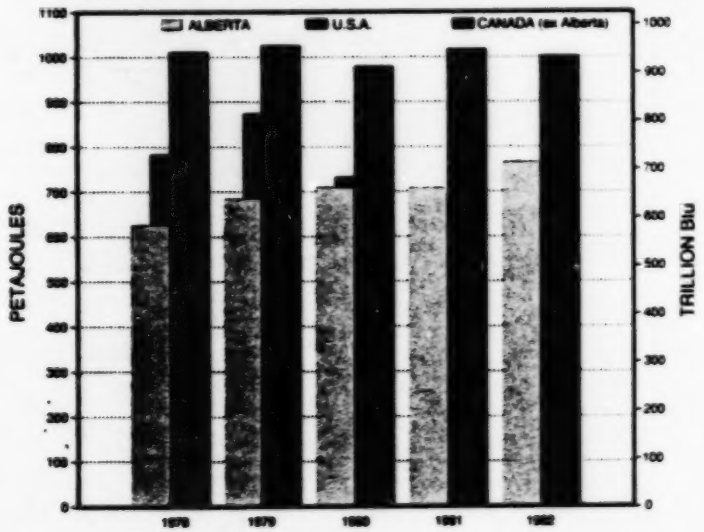
- determination of Alberta costs of service for original buyers.
- purchase of gas and its subsequent resale.
- administration of the Natural Gas Pricing Agreement Act Fund (the 'Fund') comprised of revenues derived from gas exports to the United States.
- determination of a price adjustment to be paid each month to producers with respect to eligible gas.
- reimbursement or payment of a price adjustment from revenues in the Fund.
- determination and payment of market development incentive payments to the federal government from the Fund.

NATURAL GAS SALES

During the year the Commission purchased 2 417 petajoules of natural gas, for which it paid $3 91 billion and sold for $6 33 billion, resulting in proceeds to the Fund of $2 42 billion. Total natural gas production for market was 2 504 petajoules, on which a price adjustment averaging $0 96 per gigajoule was paid from Fund proceeds.

The quantities and destination of gas sold by the Commission are shown in Figure 3.

FIG. 3
DESTINATION OF NATURAL GAS SOLD BY THE COMMISSION



NATURAL GAS PRICING

Under the Act the monthly regulated field price for natural gas purchased by original buyers that remove gas from Alberta is

Alberta Border Price
less
Alberta Cost of Service
plus
Price Adjustment

Natural gas purchased for consumption within Alberta is required to be priced as described above or at the contract field price specified in a natural gas sales contract plus a price adjustment, whichever is the lesser.

The Commission publishes the Alberta border price and determines monthly Alberta costs of service and the amount of the price adjustment.

Figure 4 shows average regulated field prices. Table 3 shows a history of the Toronto city gate price, transportation cost from Alberta to Toronto and Alberta border price.

FIG. 4
REGULATED FIELD PRICE FOR NATURAL GAS

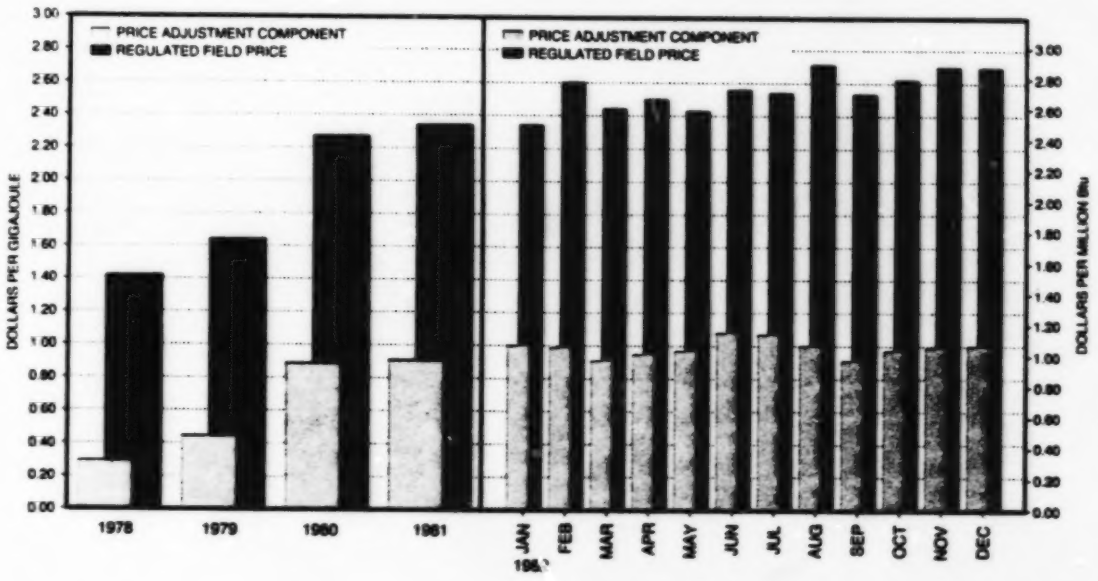


TABLE 3

HISTORY OF NATURAL GAS PRICES AND TRANSPORTATION COSTS

Date	Toronto City Gate Price	Alberta-Toronto Transportation Cost	Imputed Alberta Border Price	
	($/MMBtu)[1]	($/MMBtu)[1]	($/MMBtu)[1]	($/MMBtu)[2]
Nov. 1, 1975	1.250	.42339	.82661	.81223
Dec. 1, 1975	1.250	.41851	.83149	.81703
July 1, 1976	1.405	.43304	.97196	.95506
Jan. 1, 1977	1.505	.45272	1.05228	1.03398
Aug. 1, 1977	1.680	.46681	1.21319	1.19209
Feb. 1, 1978	1.850	.48336	1.36664	1.34287
Aug. 1, 1978	2.000	.59023	1.40977	1.38525
	($/GJ)	($/GJ)	($/GJ)	
Jan. 1, 1979[3]	1.864 06	.550 11	1.313 95	
Aug. 1, 1979	2.003 86	.590 11	1.412 97	
Feb. 1, 1980	2.143 67	.602 61	1.541 06	
Sept. 1, 1980	2.423 28	.629 20	1.794 08	
Nov. 1, 1980	2.423 28	.647 63	1.775 65[4]	
Sept. 1, 1981	2.423 28	.721 66	1.701 62[4], [5]	
Feb. 1, 1982	2.683 90	.749 27	1.934 63	
Aug. 1, 1982	2.931 83	.764 19	2.167 64	
Sept. 1, 1982	3.047 59	.879 95	2.167 64	

[1] Saturated basis (federal standard)

[2] Dry basis (Alberta standard)

[3] This does not represent a change in prices but reflects the introduction of SI commencing January 1, 1979.

[4] Established by the Government of Canada pursuant to the Petroleum Administration Act.

[5] Alberta border price confirmed by Canada-Alberta agreement effective November 1, 1981.

ALBERTA COST OF SERVICE

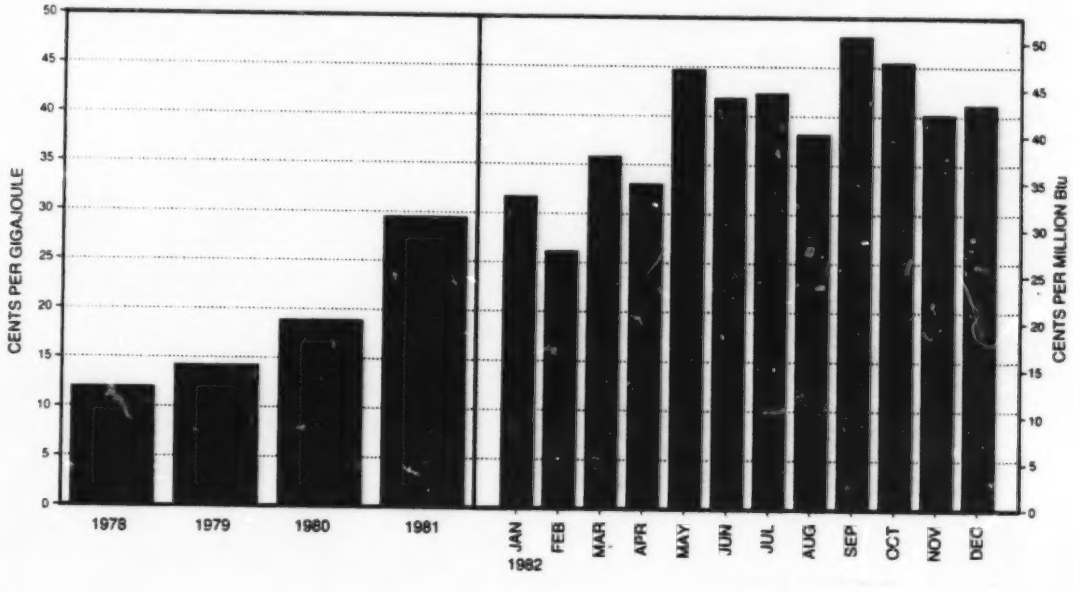
Original buyers that remove natural gas from Alberta apply to the Commission each month for determination of Alberta cost of service in respect of gas purchased in the month. The Commission makes determinations for ten original buyers, some of which apply for two or more costs of service, depending on the points of removal from Alberta, areas of supply and types of purchase contracts. Alberta costs of service consist of the costs and charges relating to the acquisition and movement of the gas from the point of purchase to the Alberta border, excluding the purchase price.

In the case of natural gas purchased by an original buyer that does not remove gas from Alberta, the Commission estimates an amount that would be the Alberta cost of service if the gas was removed from Alberta. This estimated amount is then used to determine the maximum price which the original buyer may pay for such gas.

The Commission, upon an application by an original buyer or on its own initiative, makes rulings on matters of principle and matters involving categories of costs and charges eligible for inclusion in Alberta cost of service. Any such determination made by the Commission may be appealed to the Public Utilities Board for public hearing.

The monthly averages of Alberta costs of service determined by the Commission for original buyers that remove natural gas from Alberta from 1978 through 1982 are shown in Figure 5.

FIG. 5
AVERAGE OF ALBERTA COSTS OF SERVICE



FUND TRANSACTIONS

Substantially all natural gas acquired by original buyers is purchased by the Commission. Gas destined for the Canadian market is sold back to the original buyer at the purchase price. Gas destined for export to the United States is sold back to the original buyer at the export price less transmission costs. As a result of the buy/sell transactions for export gas, proceeds are obtained for the Fund out of which price adjustment and market development incentive payments are made.

Prices for natural gas exported to the United States since November 1975 are shown in Table 4.

Each month the Commission calculates a price adjustment based on proceeds available in the Fund and estimated quantities of natural gas produced for market. Producers receive a monthly price adjustment either through the regulated field price paid by an original buyer or, in some circumstances, by claiming directly from the Fund. An original buyer that pays the price adjustment is entitled to claim reimbursement from the Fund.

The price adjustments expressed in dollars per gigajoule set by the Commission during the year were as follows:

January	0.97	May	0.94	September	0.88
February	0.96	June	1.05	October	0.94
March	0.88	July	1.04	November	0.96
April	0.92	August	0.97	December	0.97

In order to encourage expansion of markets for Alberta-produced natural gas in provinces east of Alberta, the Canada-Alberta agreement provides for market development incentive payments to be made every three months by the Commission to the federal government. These payments to the federal government are to be used to subsidize the expansion of natural gas transmission or distribution facilities and for sales promotion programs. Payments of approximately $23 million were made for the 12 months ending January 31, 1983.

TABLE 4

NATURAL GAS EXPORT PRICES

Effective Date	Export Price[1]	Average Selling Price[2]
	($/MMBtu)	($/MMBtu)
Nov. 1, 1975	1.60000	1.60000
Sept. 10, 1976	1.80000	1.80000
Jan. 1, 1977	1.94000	1.94000
Sept. 21, 1977[3]	2.16000 (U.S. $)	2.39252
	(U.S. $/GJ)	($/GJ)
Jan. 1, 1979	2.013 18	2.363 82
May 1, 1979	2.143 67	2.506 08
Aug. 11, 1979	2.610 00	3.060 59
Nov. 3, 1979	3.220 00	3.776 95
Feb. 17, 1980	4.170 00	4.845 46
Apr. 1, 1981	4.600 00	5.610 01

[1] Except for a lower price for minor quantities exported at Fort Frances since January 1, 1977.
[2] Average price in Canadian dollars received for gas exports during the period in which the export price applied.
[3] As of this date the National Energy Board prescribed the export price in U.S. $.

REGULATORY ANALYSIS

Interventions were made in several proceedings before the National Energy Board on natural gas projects, tariffs and tolls, and gas export matters.

The Commission appeared in the hearing of an application by Arctic Pilot Project Inc. to transport liquified natural gas from the Arctic islands to Eastern Canada where it would be regasified and exported to the United States. The concern of the Commission in this regard was that the costs of the regasification facilities were proposed to be included in the cost of service of TransCanada PipeLines Limited through increased tolls that would be ultimately borne by TransCanada's customers and by Alberta producers through a reduced export flowback. The hearing was postponed indefinitely when Arctic Pilot Project Inc. began considering alternate markets in Europe.

The Commission intervened, cross-examined and presented argument at a tolls and tariffs hearing for Foothills Pipelines (Yukon) Limited concerning just and reasonable tolls to be charged on the prebuild portion of the Alaska Natural Gas Transportation System. The Commission's intervention was directed in particular at the proposed allocation of $204 million of mainline costs related to the northern section of the system and the proposed amount and configuration of the prebuild's depreciation schedules. The Commission's concern was that the Alberta producer would have to bear a disproportionate share of the costs of the project. In its August 1982 decision, the National Energy Board concluded that $132 million of the mainline costs should be included in the prebuild tariff in order to enable Foothills Pipelines (Yukon) Limited to support continuation of the mainline project. The Board also directed that this amount be repaid with interest to Alberta producers when the mainline is completed and Alaskan gas flows.

In all three phases of the Gas Export Omnibus Hearing, 1982, the Commission presented evidence and argument and conducted cross examination dealing with proposed exports to the United States and Japan. In Phase I, the Commission put forth its views that contractual take or pay conditions should be included in licences and that the deliverability tests imposed by the Board should be modified. In Phase II, while neither supporting nor opposing specific export applications, the Commission voiced the opinion that use of existing facilities should be maximized for new exports and that incremental facilities should be added on a least cost approach. The Commission presented its short term demand forecast in Phase III. The Board's decision on Phase I was not to make any changes to the existing licences but to adopt more flexible surplus determination procedures. In the Phases II and III decision the Board approved new exports totalling 12.2 exajoules, of which 9.8 exajoules would flow to the United States and 2.4 exajoules to Japan in the form of liquified natural gas.

An active role was taken in the initial tolls and tariffs hearing for Trans Quebec & Maritime Pipelines Inc. The position taken was that excessive costs were proposed for inclusion in the rate base and cost of service of Trans Quebec and Maritime Pipelines Inc., particularly with respect to a portion of $44 million of development costs not directly attributable to the mainline project. The Commission maintained that these costs related to the Maritime segment of the project which would not be built and the laterals in Quebec which were no longer to be built by Trans Quebec and Maritime Pipelines Inc. In its decision, released in June 1983, the Board allowed recoverable development costs of $36.5 million.

SPECIAL STUDIES

Several studies were undertaken concerning the supply, marketing, and production of light and heavy crude oil, with particular emphasis on broadening markets for conventional crude oil.

The Commission participated in the joint IPAC - Government of Alberta assessment of a multi-use gas storage facility.

A program of sampling and analysis of major light and heavy crude oil feeder pipeline streams, synthetic oil, bitumen and pentanes plus was continued. These analyses provide information related to the product yield that can be obtained from each stream and thereby assist in marketing.

SYNCRUDE PROJECT

Petroleum derived from oil sands leases is not required by statute to be priced or marketed by the Commission. However, the Commission performs certain functions related to the Syncrude Canada Limited project. The Commission markets the Province of Alberta's share of synthetic oil and, by agreement, the share of one other participant. The province has a 16.74 per cent equity participation in the project and a 50 per cent share of deemed net profits in lieu of royalty. In 1982 the net profits share was taken as production in kind with the result that during the year the Commission marketed approximately 32 per cent of the total 4 977 716.8 cubic metres of synthetic oil produced by the project.

In addition to the Commission's functions, the Chairman of the Commission is the Alberta Royalty Negotiator with respect to synthetic oil produced by the project. This involves establishment of the value of synthetic oil to be used as a factor in determining net profits. At year end this value was $282.45 per cubic metre at the plant gate, including compensation of $115.95 per cubic metre paid by the federal government to reflect international prices.

WORLD ENERGY SCENE

INTERNATIONAL (excluding communist countries)

For the fourth consecutive year, world energy consumption declined, intensifying competition among alternative energy forms. The 2.2 percent decline in overall energy use was primarily due to conservation and the world recession.

Table 5 highlights the pattern of world energy consumption since 1978. It shows a decline in the world's reliance on oil and a corresponding increase in the use of coal, hydro, and nuclear electricity.

It was a dynamic year for the world petroleum industry that marked an important turning point in the relationship between oil producing and consuming countries. The crude oil surplus which had developed the year before could not be constrained by OPEC, whose failure in this regard was widely interpreted as a victory for market forces and a signal that OPEC was no longer in a position to control pricing.

World crude oil production declined 7.3 percent as a result of reduced petroleum product consumption and worldwide inventory reduction. As shown in Figure 6, OPEC shouldered all of the decline in demand. Its share of world supply dropped from 48.2 percent in 1981 to 42.7 percent.

Competition for markets among OPEC members created problems within the organization and led to speculation that OPEC's collapse was imminent. Price discounting by some OPEC members and official price cuts by non-OPEC producing countries put considerable pressure on the structure of world oil prices. In March of 1983, OPEC was able to reach a consensus on pricing and production quotas. Figure 7 compares spot and official prices for Arab light crude and demonstrates the volatile pricing in the 1979-82 period.

The year was also a period of transition for the world's refining community. Two trends were evident. Firstly, there was a shift in the nature of crude oil supply arrangements. Long term contracts, once valued for security of supply reasons, were all but abandoned in favor of spot purchases. This departure from historical practice allowed refiners to shop for crude oil bargains, and was a significant factor in the events which led to a downward ratcheting of world oil prices.

Secondly, there was an ongoing decline in the world's crude oil refining capacity. Eighty-four refineries were shut down worldwide, most of which were in the U.S.A. Those that remained were more efficient in the conversion of residual products into lighter, more valuable fuels. Despite these changes, refining profitability remained extremely low.

Natural gas production declined by 5.3 percent. There was a corresponding decline in internationally traded gas via pipeline systems, most apparent in continental Europe. Lower rates of production translated into unused gas plant capacity of 23 percent. Algeria was the hardest hit with unused capacity of 50 percent. Liquified natural gas production in OPEC and non-OPEC nations declined 14.1 percent and 1.0 percent respectively.

More coal was consumed worldwide in 1982 than in any previous year. Coal producing countries such as Canada and the United States increased their production to satisfy increased demand. However, the United Kingdom and West Germany both registered production declines.

Worldwide, primary electricity production increased 3.8 percent to 2176.3 billion kilowatt hours.

TABLE 5

WORLD CONSUMPTION OF PRIMARY ENERGY BY SOURCE*

(Percentage Shares)

	1978	1979	1980	1981	1982
Petroleum	53.3	52.5	50.0	48.2	47.4
Natural Gas	17.8	17.7	18.4	19.1	18.5
Coal	18.7	19.6	21.1	21.6	22.0
Hydro Electricity	7.2	7.2	7.4	7.5	8.0
Nuclear Electricity	3.0	3.0	3.1	3.6	4.1

* Excludes Communist countries

FIG. 6
WORLD CRUDE OIL SUPPLY & DEMAND
(excluding communist countries)

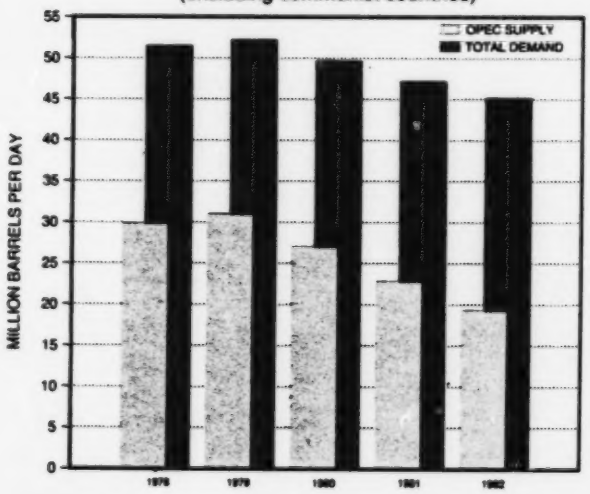
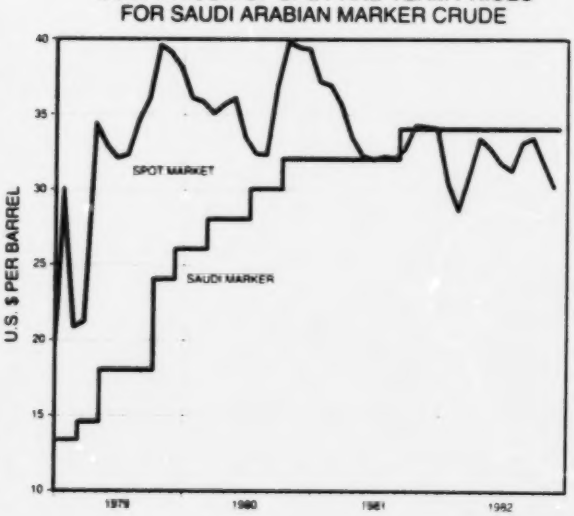


FIG. 7
COMPARISON OF SPOT AND TERM PRICES
FOR SAUDI ARABIAN MARKER CRUDE



UNITED STATES

There was intense market competition among oil, gas, coal and electricity, as a result of the decline in energy demand and an excess of energy supplies. Economic recession and conservation combined to reduce energy consumption by four percent.

Oil prices, reacting to increased domestic supply and soft demand conditions, remained below OPEC prices through the year. Refiner acquisition costs for domestic crude oil declined by more than $3.11 (U.S.) per barrel. This downward trend contrasted with higher natural gas prices which, in spite of excess deliverability, continued to move upward due largely to the regulation of prices under the Natural Gas Policy Act.

Demand for petroleum fell by five percent. In response to lower revenues and profits, 77 refineries were closed down. Still, capacity utilization remained at low levels, averaging 70 percent for the year.

Petroleum production increased marginally due to increased drilling activity in the Lower 48 states and additional production from Alaska. Although the number of exploratory and development wells drilled increased by seven percent, this gain reflected the high number of rigs operating in the early part of the year. After that time, drilling fell drastically because of the depressed investment climate created by falling prices and lower demand.

Petroleum imports declined for the third consecutive year, to five million barrels per day, which was 43 percent lower than in the peak year of 1977. Crude imports fell 21 percent and product imports declined by one percent. Mexico replaced Saudi Arabia as the exporter of largest volumes of crude oil to the United States. Imports from Canada and Nigeria also increased. Figure 8 shows sources of petroleum supply since 1978.

Events during the year forced a re-appraisal of natural gas regulation in the United States which operated to place natural gas at a competitive disadvantage relative to alternative fuels in some markets. Natural gas consumption declined 7.5 percent to 17.8 trillion cubic feet. Largely as a result of lower throughput, increased unit pipeline transportation costs further eroded the competitive position of natural gas.

Increasing natural gas prices reached critical levels in the latter half of the year when gas prices in the large industrial and boiler fuel market exceeded those of competing fuels. In these markets, which accounted for almost one-half of total natural gas consumed, natural gas use declined 13.5 percent. Table 6 illustrates consumption among competing energy forms, and table 7 provides a history of the cost of fossil fuels delivered to steam-electric utility plants since 1978.

In an attempt to limit gas acquisition costs, transmission companies renegotiated or cancelled purchase contracts for high priced (deregulated) gas, driving down the market price for much of this gas from over $10.00 (U.S.) per million cubic feet to under $5.00 (U.S.) per million cubic feet. This trend applied pressure on prices for other high-cost supplemental supplies, including pipeline imports, synthetic natural gas and liquified natural gas. In April, the sponsors of the Alaska Natural Gas Transportation System project announced that construction would be delayed further.

Imports of Canadian natural gas increased by three percent, due to the first full year of service for the Western Leg of the prebuild portion of the Alaska Natural Gas Transportation System and the later start-up of the Eastern Leg. Most Canadian sales into traditional market areas were limited to minimum volumes under existing contracts. The reduction of imports into the Midwest in the last quarter of the year forewarned of the difficulty to be experienced in marketing Canadian gas in the United States.

The number of gas wells drilled increased six percent and proven reserves increased from 198 to 204 trillion cubic feet. Drilling for deep gas has effectively ceased and will not likely resume for several years.

Total electricity generation declined by 2.3 percent. Hydro and nuclear sourced generation increased 18 percent and 2.3 percent respectively while generation from fossil fuels declined 6.3 percent.

TABLE 6

UNITED STATES PRIMARY ENERGY CONSUMPTION

(Quadrillion Btu's)

	Petroleum*	Natural Gas (Dry)	Coal	Hydro Electricity	Nuclear Electricity	Other	Total
1978	37.965	20.000	13.846	3.141	3.024	0.199	78.175
1979	37.123	20.666	15.109	3.141	2.715	0.156	78.910
1980	34.202	20.391	15.461	3.118	2.739	0.077	75.988
1981	31.931	19.930	15.973	3.066	2.974	0.110	73.984
1982	30.332	18.426	15.423	3.574	3.084	0.085	70.924

* includes refined petroleum products and natural gas liquids.

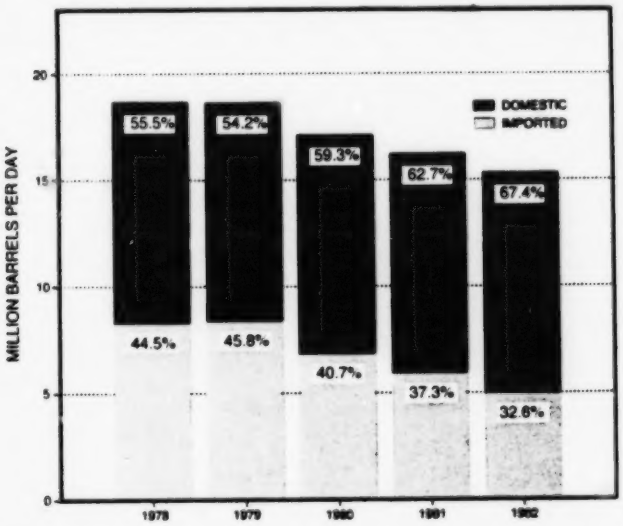
TABLE 7

COST OF FOSSIL FUEL DELIVERED TO STEAM ELECTRIC UTILITY PLANTS IN THE U.S.

(U.S.$ per million Btu's)

	Coal	Residual Oil	Natural Gas
1978	1.12	2.12	1.44
1979	1.22	3.00	1.75
1980	1.35	4.28	2.21
1981	1.53	5.29	2.83
1982	1.65	4.75	3.40

FIG. 8
TOTAL UNITED STATES CONSUMPTION OF PETROLEUM



CANADA

Reduced domestic oil consumption and continuing imports, combined with export restrictions resulted in an average 15.0 thousand cubic metres per day of shut-in crude oil, including 11.1 thousand cubic metres per day in Alberta. This volume would have been greater without subsidized movements of domestic crude oil to the Atlantic region, which began in July.

Demand for petroleum products fell 10.2 percent. This translated to a 14.7 percent decline in demand for crude oil because of large inventory reductions in response to the shrinking market. Imports of crude oil averaged 44.0 thousand cubic metres per day.

Seven Canadian refineries were closed or their closures announced in late 1982 and early 1983, as a result of falling product demand. These comprised three in Quebec, one each in Nova Scotia, Ontario, Manitoba and British Columbia. These closures resulted in a capacity loss of 50.4 thousand cubic metres per day. Refining capacity utilization averaged only 66.0 percent. Against this trend, one refinery opened in Alberta.

The number of oil and gas wells drilled in Canada fell by 8.7 percent, with the largest reduction in exploratory wells which dropped by 25.4 percent. These trends occurred for all regions with the exception of Manitoba and the Northwest Territories. Some increased activity was achieved in Alberta later in the year as a result of drilling and well-servicing incentives introduced by the Alberta government in April. Exploratory expenditures have been increasing in higher risk frontier areas, aided by exploration grants.

Remaining established reserves of conventional crude oil in Western Canada have decreased at an average rate of 3.9 percent per year for the last 13 years, with a decline of 4.8 percent in 1982. Including frontier areas, remaining

established crude oil reserves in Canada at the end of 1982 totalled 1 021 million cubic metres, a reduction of 4 0 percent from 1981 year-end estimates.

Natural gas consumption increased by 2 4 percent, almost entirely due to an 8 1 percent increase in sales within Alberta. Exports of natural gas increased by 2 9 percent. However, exports were less than one half of licensed volumes.

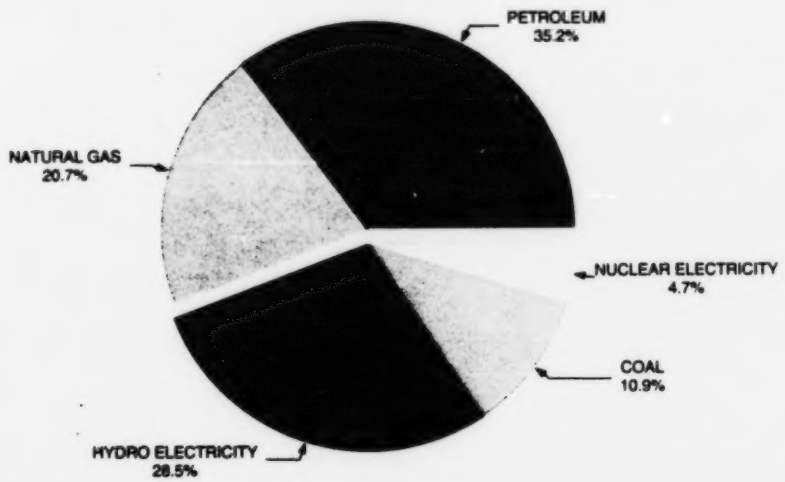
Production of marketable natural gas in Canada totalled 69 3 billion cubic metres in 1982, an increase of 2 0 percent over 1981. Alberta production was 88 4 percent of the total or 61 3 billion cubic metres. This was an increase of 3 3 percent over the 1981 level. Canadian established reserves of marketable natural gas increased 1 1 percent to 2 591 billion cubic metres, yielding a 37 year reserve life index at 1982 average production levels.

The development of large-scale oil sands plants was set back with the cancellation of the Alsands and Esso Cold Lake projects. The cash flow problems and poor investment climate that faced the oil and gas industry will have important long term implications for crude oil and natural gas development in Canada.

For the second consecutive year Canada was a net exporter of coal. Approximately 15 8 megatonnes of coal were imported, primarily into Ontario, and 16 0 megatonnes were exported, primarily from Western Canada. Domestic production increased by 6 8 percent in 1982 to 42 8 megatonnes.

Electricity generation totalled 375 4 billion kilowatt hours, a decline of 0 8 percent. Exports to the United States declined 3 3 percent to 34 2 billion kilowatt hours, while domestic consumption declined 0 2 percent to 344 1 billion kilowatt hours.

FIG. 9
1982 CANADIAN ENERGY CONSUMPTION



OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1982 and the statements of revenue and expenditure for the Operating Fund and the Petroleum Marketing Fund for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Commission as at December 31, 1982 and the results of its operations for the year then ended in accordance with the disclosed basis of accounting described in Note 2 to the financial statements applied, after giving retroactive effect to the change in the method of accounting for leasehold improvements as described in Note 3 to the financial statements, on a basis consistent with that of the preceding year.

C.A.
Auditor General

Edmonton, Alberta
May 5, 1983

Alberta PETROLEUM MARKETING COMMISSION

BALANCE SHEET

As At December 31

ASSETS

	1982	1981
OPERATING FUND		
Current Assets		
Cash (Note 4)	**$ 3,182,429**	$ 2,544,292
Accounts receivable	**422,186**	510,073
Prepaid expenses	**—**	914
	3,604,615	3,055,279
Furniture, equipment and leasehold improvements, at cost	**1,719,602**	1,060,047
	5,324,217	4,115,326
PETROLEUM MARKETING FUND		
Current Assets		
Cash (Note 4)	**14,617,560**	9,837,814
Accounts receivable (Note 5)	**780,832,040**	578,727,072
Inventory, at cost	**26,207,644**	14,751,188
	821,657,244	603,316,074
	$826,981,461	$607,431,400

The accompanying notes are part of these financial statements.

LIABILITIES

	1982	1981
OPERATING FUND		
Current Liabilities		
Accounts payable	**$ 181,895**	$ 549,744
Deferred revenue	**3,422,720**	2,505,535
	3,604,615	3,055,279
Capital surplus	**1,719,602**	1,060,047
	5,324,217	4,115,326
PETROLEUM MARKETING FUND		
Current Liabilities		
Accounts payable to Crown lessees	**485,215,417**	328,270,673
Crown royalty payable	**257,764,597**	236,282,479
Buy/sell, freehold and transportation payable	**78,677,230**	38,762,922
	821,657,244	603,316,074
	$826,981,461	$607,431,400

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
OPERATING FUND

For The Years Ended December 31

	1982	1981
Revenue		
Contributions by the Province of Alberta	**$3,436,473**	$2,209,121
Interest earnings	**2,127,388**	2,310,168
	5,563,861	4,519,289
Expenditure		
Salaries and wages	**2,883,379**	2,037,259
Technical studies	**493,731**	452,677
Furniture and equipment	**411,498**	577,750
Rental of premises (Note 8)	**339,622**	343,751
Employee benefits	**302,082**	187,317
Computer services	**282,989**	134,667
Leasehold improvements	**231,500**	240,572
Travel and business meetings	**193,719**	186,832
Printing, stationery and office supplies	**107,387**	87,274
Personnel consultants	**99,026**	91,544
Library publications and periodicals	**52,842**	27,091
Advertising	**52,538**	32,808
Rental of office equipment and furnishings	**50,192**	36,904
Telephone	**23,649**	26,359
Postage and freight	**16,372**	41,101
Equipment maintenance	**9,621**	4,315
Insurance	**421**	1,712
Miscellaneous	**13,293**	9,356
	5,563,861	4,519,289
Excess of revenue over expenditure	**$ —**	$ —

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
PETROLEUM MARKETING FUND

For The Years Ended December 31

	1982	1981
Revenue (Note 6)		
Sale of petroleum, pentanes plus and bitumen	**$7,811,707,747**	$5,565,440,064
New oil reference price supplement	**239,023,829**	—
Special old oil price supplement	**113,529,857**	—
	8,164,261,433	5,565,440,064
Expenditure		
Purchases	**567,601,166**	273,207,851
Transportation	**115,624,758**	95,013,988
	683,225,924	368,221,839
Lessees' share	**4,888,577,292**	3,134,982,788
Royalty share	**2,592,458,217**	2,062,235,437
	8,164,261,433	5,565,440,064
Excess of revenue over expenditure	**$ —**	$ —

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1982

Note 1 Authority

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980.

Note 2 Significant Accounting Policies

General

These financial statements have been prepared in accordance with generally accepted accounting principles except that no depreciation or amortization has been provided on fixed assets as purchases are charged to operating fund expenditure in the year of acquisition. Furniture, equipment and leasehold improvements are shown on the balance sheet at original cost with the offsetting credit to capital surplus.

Deferred Revenue

The unexpended portion of contributions received from the Province of Alberta has been deferred to cover operating costs for the period to March 31, 1983. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

Operating Fund Expenditure

The Natural Gas Pricing Agreement Act Fund is administered by the Alberta Petroleum Marketing Commission pursuant to the Natural Gas Pricing Agreement Act. The expenditure related to the administration of this Fund is reflected in the Statement of Revenue and Expenditure — Operating Fund.

Inventory

The inventory represents the Crown royalty share of petroleum and pentanes plus deliveries remaining in the feeder pipelines at December 31.

Statement of Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Change in Accounting Policies

During the year the Commission changed its accounting policies to include the cost of leasehold improvements as an asset on the balance sheet. This change was applied retroactively to December 1981, the date of the Commission's move to its present leased premises.

Note 4 Cash

Arrangements with the Commission's bankers provide for interest at commercial rates on all account balances.

Note 5 Petroleum Marketing Fund Accounts Receivable

Petroleum Marketing Fund accounts receivable consist of the following:

	1982	1981
Transactions related to December petroleum deliveries	**$772,927,612**	$578,491,502
Prior months' accounts, net	**7,904,428**	235,570
	$780,832,040	$578,727,072

Note 6 Revenue

Marketing of Pentanes Plus

Effective January 1, 1982, the Commission became the exclusive agent to accept delivery of, and market the Crown's royalty and lessees' share of pentanes plus. The revenue from these transactions is included in 'Sale of petroleum, pentanes plus and bitumen'.

New Oil Reference Price Supplement Payments

Effective January 1, 1982, pursuant to the Canada-Alberta agreement on energy pricing dated September 1, 1981, oil discovered after December 31, 1980 became eligible for the New Oil Reference Price (NORP). NORP supplement payments were received from the federal government for the difference between the established NORP price and the field price for conventional old oil. The NORP supplement payments were extended to cover pentanes plus and bitumen effective April 1, 1982.

Special Old Oil Price Supplement Payments

Effective July 1, 1982, pursuant to The National Energy Program Update of May 1982, oil discovered from April 1, 1974 to December 31, 1980 became eligible for the Special Old Oil Price (SOOP). Pentanes plus discovered from January 1, 1974 to December 31, 1980 also became eligible for the SOOP price on July 1, 1982. SOOP supplement payments were received from the federal government for the difference between the established SOOP price and the field price for conventional old oil.

Note 7 Syncrude Project

The Commission, through agency agreements with the Province of Alberta and PanCanadian Petroleum Limited, markets their shares of synthetic oil from the Syncrude Project. The Commission, acting by appointment from the Minister of Energy and Natural Resources, also markets the Crown royalty share of synthetic oil.

The marketing activities undertaken by the Commission relative to these transactions are not reflected in these financial statements.

Note 8 Lease Commitment

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of $692,360.

The 1982 expenditure for 'Rental of premises' has been reduced by an amount of $549,727. This amount was paid to the Commission by the landlord pursuant to an agreement which compensated for the difference between the rental rate on the square footage at its' former location and the rate at the new location, for the period to the expiry of the old lease in June 1984.

Note 9 Subsequent Events

On March 31, 1983, the Commission assigned to the Provincial Treasurer of the Province of Alberta, an indebtedness of $46,792,504 ($24,109,073 as at December 31, 1982) due from a petroleum purchaser for deliveries made prior to February 9, 1983. The consideration for this assignment was an equivalent reduction in the amount payable to the Crown from the sale of the royalty share of petroleum. Credit was extended to the purchaser following arrangements with the Provincial Government.

Note 10 Comparative Figures

The 1981 figures have been restated where necessary to conform to the 1982 presentation.

Note 11 Approval of Financial Statements

These financial statements were approved by management on May 5, 1983.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Pricing Agreement Act Fund as at December 31, 1982 and the statement of revenue and expenditure for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1982 and the results of its operations for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding period.

C.A.
Auditor General

Edmonton, Alberta
May 5, 1983

NATURAL GAS PRICING AGREEMENT ACT FUND

BALANCE SHEET

As At December 31

ASSETS

	1982	1981
Current Assets		
Cash (Note 3)	**$ 13,203,335**	$ 21,924,996
Accounts receivable (Note 4)	**255,542,145**	256,213,349
	$268,745,480	$278,138,345

LIABILITIES

Current Liabilities		
Price adjustments payable	**$268,745,480**	$274,315,468
Market development incentive payable (Note 5)	**—**	3,822,877
	$268,745,480	$278,138,345

The accompanying notes are part of these financial statements.

NATURAL GAS PRICING AGREEMENT ACT FUND

STATEMENT OF REVENUE AND EXPENDITURE

For The Year Ended December 31, 1982 (Note 6)

Revenue	
Natural gas sales	**$6,330,714,339**
Interest earnings	**2,778,697**
	6,333,493,036
Expenditure	
Natural gas purchases	**3,906,419,781**
Price adjustments	**2,402,343,405**
Market development incentive (Note 5)	**24,729,850**
	6,333,493,036
Excess of revenue over expenditure	**$ —**

NATURAL GAS PRICING AGREEMENT ACT FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1982

Note 1 Authority

The Natural Gas Pricing Agreement Act Fund is established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended.

Note 2 Significant Accounting Policies

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure — Operating Fund.

Statement of Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Cash

Arrangements with the Commission's bankers provide for interest at commercial rates on all account balances

Note 4 Accounts Receivable

Accounts receivable consist primarily of net proceeds from December natural gas sales.

Note 5 Market Development Incentive Payments

Pursuant to the Canada-Alberta agreement on gas pricing of November, 1981, payments out of the Fund are required to be made by the Commission to the Government of Canada for the purpose of facilitating the expansion of markets in provinces east of Alberta for gas produced in Alberta.

Note 6 Comparative Figures

Inasmuch as the statement of revenue and expenditure for the Fund included two months only in the previous fiscal year, comparative figures have not been presented. Transactions prior to November 1, 1981 were reflected in the financial statements of the Natural Gas Price Administration Act Fund.

Note 7 Approval of Financial Statements

These financial statements were approved by management on May 5, 1983.

COMMISSION PERSONNEL

COMMISSION MEMBERS

Chairman	D.W. Minion
Vice Chairman	R.H. Purdy
Member	R.D. Hall

SECRETARY AND SOLICITOR ..... D.C. Hetland

COMMISSION AUDITOR ..... E.K. Adams

ADMINISTRATION

Administrative Assistant	D. MacLachlan
Manager, Office Services	B.A. Lilly

ENGINEERING & PLANNING

General Manager	R.S. Dunwald
Manager, Technical Evaluations	G.E. Baerg

FINANCE

General Manager	G.K. Palmer
Manager, Accounting	T.N.R. Fons

NATURAL GAS

General Manager	V.M. Thomas
Manager, Cost of Service	W.A. McKain
Manager, Natural Gas Sales & Claims	A. Smith
Manager, Regulatory Analysis	H.D. Maerz

PETROLEUM

General Manager	J.E. MacKenzie
Manager, Petroleum Marketing	R.J. McLean
Manager, Petroleum Operations	R.J. Smith
Manager, Petroleum Supply	D.M. Olineck

SYSTEMS DEVELOPMENT & COMPUTER SERVICES

Senior Advisor	R.W. Tovell
Manager, Computer Services	S. Leung
Manager, Systems Development	S.J. Myra

STAFF AND OFFICES

At December 31, 1982 the staff of the Commission numbered 99. The Commission head office is in Calgary and it maintains an office in Edmonton.